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SUMMER 2006 ELECTRICITY SUPPLY AND DEMAND OUTLOOK

STAFF DRAFT REPORT

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Table of Contents

Page

Tables

Figures

INTRODUCTION AND SUMMARY

The draft *Summer 2006 Electricity Supply and Demand Outlook* provides the California Energy Commission (Energy Commission) staff's current assessment of physical electricity resource adequacy in California. It evaluates the capability of the electricity system to provide power to electricity demand in specific geographic areas within California. It does not evaluate the condition of the electricity market or the deliverability of economic contracts entered into by load serving entities. The analysis was prepared in coordination and consultation with the California Public Utilities Commission (CPUC) and the California Independent System Operator (CA ISO). A staff workshop is scheduled for December 8, 2005 to receive stakeholder and public input on the draft outlook.

This outlook examines four regions - California Statewide, CA ISO Control Area, CA ISO North of Path 26 (NP26), and CA ISO South of Path 26 (SP26). The CA ISO Control Area is divided into Northern and Southern California because there are transmission constraints south of the transmission segment known as Path 26, which limits the transfer of electricity from north to south. Northern California includes the Pacific Gas and Electric (PG&E) service area and participating municipal utilities in Northern California served by the CA ISO. Southern California includes Southern California Edison (SCE), San Diego Gas and Electric (SDG&E), and the southern California municipal utilities that participate in the CA ISO

Methodology Updates from 2005

This outlook uses the high demand forecast[1] developed for the 2005 Integrated Energy Policy Report for forecasted loads in each region.

This assessment includes several methodology changes as a result of comments received during our workshop on the *Summer 2005 Electricity Supply and Demand Outlook* held in March 2005. Two consistent comments from workshop participants were: (1) demand response and interruptible load programs are essential to the planning and operation of the daily system, and these resources should be included in the outlook tables; and (2) using above-average forced outages and transmission limitations in the 1-in-2 scenario could result in the procurement of unnecessary resources. These suggestions have been incorporated into our revised methodology.

A second major change from our 2005 outlook is provided in Chapter 2. Staff is in the initial stages of developing full probabilistic assessments to enhance the deterministic tables we have historically completed. This first stage studies the probabilities of variations in demand and forced outages in the Southern California

[1] California Energy Demand 2006-2016 Revised September 2005. CEC-400-2005-034-SF-ED2

portion of the CA ISO Control Area. These two criteria were selected for initial probabilistic analysis because higher demand from hot temperatures and outage fluctuations have significant impacts on the overall operation of the system, and the data to estimate probabilities is available.

Results

The 2006 summer outlook is presented in three scenarios. The first scenario calculates the planning reserve margin using the 15-17 percent reserve criteria required by the CPUC for June 2006. Planning reserves are calculated for derated generation before taking into account potential outages. Planning reserves are higher than operating reserves because they cover multiple contingencies. The second scenario calculates operating reserves representing conditions that could be expected on an average summer day, including estimated outages. Finally, an adverse scenario is included to show possible results from several conditions that might simultaneously occur to stress the system.

Energy Commission staff expects supplies in all regions will be adequate to meet growing electricity demand and the required 7 percent operating reserves[2] under average (1-in-2 or a 50 percent probability) temperature conditions. Improved resource adequacy is due to the addition of new generation facilities since 2000, transmission improvements, increased energy efficiency, and voluntary conservation.

If very hot summer demand occurs (1-in-10 or a 10 percent probability), Northern California electricity resources are expected to exceed the 7 percent reserve requirement. In the last several years, more new generation has been built in this region than in the south, and demand growth has been slower. Northern California typically reaches its summer peak during July.

The summer 2006 projection for Southern California have improved compared to 2005. Southern California resources are also expected to exceed the minimum reserve requirement under average (1-in-2) weather conditions. Under hot (1-in-10) weather conditions, demand response and interruptible programs may need to be used if adverse conditions of high zonal limitations (transmission congestion) and high forced outages occur simultaneously. No loss of firm load is expected. Peak electricity demand in Southern California usually occurs in September; however in 2005, a new record peak demand occurred on July 20, 2005.

Southern California areas served by the municipal utilities that are not members of the CA ISO, including Los Angeles Department of Water and Power (LADWP), Burbank Water and Power, Glendale Water and Power, and Imperial Irrigation District, appear to have adequate resources. The LADWP, in particular, should have surplus power available to provide to the rest of the region if satisfactory

[2] The Western Electricity Coordination Council requires a 7 percent operating reserve for thermal resources and a five percent operating reserve for hydro resources.

contractual agreements can be implemented between California's largest municipal utility and the appropriate load serving entity.

Northern California and Southern California monthly electricity demand and supply outlooks for Summer 2006 are presented in addition to the Statewide and CA ISO Control Area Outlooks in Tables 1-1 through 1-4. Chapter 1 documents line by line the Energy Commission staff's supporting information and assumptions used in these assessments.

Table 1-1: 2006 Detailed Monthly Electricity Outlook – California Statewide
(Megawatts)

	Resource Adequacy Planning Conventions	June	July	August	September
1	Existing Generation[1]	56,364	57,377	57,377	57,377
2	Retirements (Known)	-1,539	0	0	0
3	High Probability CA Additions	2,552	0	0	0
4	Net Interchange [2]	13,118	13,118	13,118	13,118
5	Total Net Generation (MW)	70,495	70,495	70,495	70,495
6	1-in-2 Summer Temperature Demand (Average)[3]	55,119	57,626	58,228	57,318
7	Demand Response (DR)	691	691	691	691
8	Interruptible/Curtailable Programs	1,349	1,349	1,349	1,349
9	Planning Reserve[4]	31.6%	25.9%	24.6%	26.5%
	Expected Operating Conditions				
10	Outages (Average forced + planned)	-2,570	-2,570	-2,570	-2,570
11	Zonal Transmission Limitation[5]	-150	-150	-150	-150
12	Expected Operating Generation with Outages/Limitations[6]	67,775	67,775	67,775	67,775
13	Expected Operating Reserve Margin (1-in-2)[7]	29.4%	22.3%	20.7%	23.1%
	Adverse Conditions				
14	High Zonal Transmission Limitation	-250	-250	-250	-250
15	High Forced Outages (1 STD above average)	-1,160	-1,160	-1,160	-1,160
16	Adverse Temperature Impact (1-in-10)	-3,331	-3,502	-3,627	-3,524
17	Adverse Scenario Reserve Margin[7]	17.1%	10.7%	9.1%	11.3%
18	Adverse Scenario Reserve Margin w/DR and Interruptibles[8]	21.5%	14.8%	13.2%	15.5%
19	Resources needed to meet 7.0% Reserve (W/DR & Interruptibles)	0	0	0	0
20	Surplus Resources Above 7.0% Reserve (W/DR & Interruptibles)	6,712	3,846	3,068	4,152
21	Existing Generation Without Capacity Contracts[9]	-3,722	-3,722	-3,722	-3,722

[1] Dependable capacity by station includes 1,080 MW of stations located South of Miguel.
[2] 2006 estimate of the following Net Imports: **DC imports 2,000 MW, SW imports 4,100 MW, NW imports (COI) 4,000 MW, LADWP Control Area imports 2,834 MW, IID Imports 184 MW**. **Imports with own reserves highlighted in bold.**
[3] Demand forecast completed September 2005 as part of IEPR proceeding. CEC-400-2005-034-SF-ED2
[4] Planning Reserve calculation ((Total Generation+Demand Response+Interruptibles)/Normal Demand)-1.
[5] Based on CA ISO data.
[6] Does not include Demand Response/Interruptible Programs due to Reserve Margins in excess of 5% (Stage 2).
[7] Operating Reserve calculation ((Operating Generation-**Imports with Reserves**)/(Demand-**Imports with Reserves**))-1. See Footnote 2.
[8] Demand Response and Interruptibles added to Operating Generation in Reserve Margin formula from Footnote 7.
[9] Capacity is included in Line 1 and represents plants identified in 2004 CEC Staff Draft Report 100-04-005D Resource, Reliability and Environmental Concerns of Aging Power Plant Operations and Retirements

12/5/2005

Table 1-2: 2006 Detailed Monthly Electricity Outlook – CA ISO Control Area
(Megawatts)

	Resource Adequacy Planning Conventions	June	July	August	September
1	Existing Generation[1]	45,894	46,102	46,102	46,102
2	Retirements (Known)	-1,539	0	0	0
3	High Probability CA Additions	1,747	0	0	0
4	Net Interchange [2]	10,650	10,650	10,650	10,650
5	Total Net Generation (MW)	56,752	56,752	56,752	56,752
6	1-in-2 Summer Temperature Demand (Average)[3]	44,245	46,147	46,287	45,865
7	Demand Response (DR)	691	691	691	691
8	Interruptible/Curtailable Programs	1,149	1,149	1,149	1,149
9	Planning Reserve[4]	32.4%	27.0%	26.6%	27.7%
	Expected Operating Conditions				
10	Outages (Average forced + planned)	-2,170	-2,170	-2,170	-2,170
11	Zonal Transmission Limitation[5]	-150	-150	-150	-150
12	Expected Operating Generation with Outages/Limitations[6]	54,432	54,432	54,432	54,432
13	Expected Operating Reserve Margin (1-in-2)[7]	29.4%	22.7%	22.2%	23.7%
	Adverse Conditions				
14	High Zonal Transmission Limitation	-250	-250	-250	-250
15	High Forced Outages (1 STD above average)	-1,060	-1060	-1060	-1060
16	Adverse Temperature Impact (1-in-10)	-2,560	-2,689	-2,712	-2,713
17	Adverse Scenario Reserve Margin[7]	17.0%	10.9%	10.5%	11.7%
18	Adverse Scenario Reserve Margin w/DR and Interruptibles[8]	22.0%	15.6%	15.2%	16.4%
19	Resources needed to meet 7.0% Reserve (W/DR & Interruptibles)	0	0	0	0
20	Surplus Resources Above 7.0% Reserve (W/DR & Interruptibles)	5,556	3,383	3,209	3,659
21	Existing Generation Without Capacity Contracts[9]	-3,722	-3,722	-3,722	-3,722

[1] Dependable capacity by station includes 1,080 MW of stations located South of Miguel.

[2] 2006 estimate of the following Net Imports: **DC imports 2,000 MW, SW imports 4,100 MW, NW imports (COI) 4,000 MW, TID/MID -450MW**, LADWP Control Area imports 1,000 MW. **Imports with own reserves highlighted in bold.**

[3] Demand forecast completed September 2005 as part of IEPR proceeding. CEC-400-2005-034-SF-ED2

[4] Planning Reserve calculation ((Total Generation+Demand Response+Interruptibles)/Normal Demand)-1.

[5] Based on CA ISO data.

[6] Does not include Demand Response/Interruptible Programs due to Reserve Margins in excess of 5% (Stage 2).

[7] Operating Reserve calculation ((Operating Generation-**Imports with Reserves**)/(Demand-**Imports with Reserves**))-1. See Footnote 2.

[8] Demand Response and Interruptibles added to Operating Generation in Reserve Margin formula from Footnote 7.

[9] Capacity is included in Line 1 and represents plants identified in 2004 CEC Staff Draft Report 100-04-005D Resource, Reliability and Environmental Concerns of Aging Power Plant Operations and Retirements

12/5/2005

Table 1-3: 2006 Detailed Monthly Electricity Outlook – CA ISO Northern Region (NP26)
(Megawatts)

Resource Adequacy Planning Conventions		June	July	August	September
1	Existing Generation	24,573	24,394	24,394	24,394
2	Retirements (Known)	-219	0	0	0
3	High Probability CA Additions	40	0	0	0
4	Net Interchange [1]	550	550	550	550
5	Total Net Generation (MW)	24,944	24,944	24,944	24,944
6	1-in-2 Summer Temperature Demand (Average)[2]	19,964	20,395	20,121	19,384
7	Demand Response (DR)	245	245	245	245
8	Interruptible/Curtailable Programs	260	260	260	260
9	Planning Reserve[3]	27.5%	24.8%	26.5%	31.3%
Expected Operating Conditions					
10	Outages (Average forced + planned)	-1,100	-1,100	-1,100	-1,100
11	Zonal Transmission Limitation[4]	0	0	0	0
12	Expected Operating Generation with Outages/Limitations[5]	23,844	23,844	23,844	23,844
13	Expected Operating Reserve Margin (1-in-2)[6]	20.0%	17.4%	19.0%	23.7%
Adverse Conditions					
14	High Zonal Transmission Limitation	0	0	0	0
15	High Forced Outages (1 STD above average)	-500	-500	-500	-500
16	Adverse Temperature Impact (1-in-10)	-654	-668	-660	-635
17	Adverse Scenario Reserve Margin[6]	13.6%	11.1%	12.7%	17.1%
18	Adverse Scenario Reserve Margin w/DR and Interruptibles[7]	16.1%	13.6%	15.2%	19.7%
19	Resources needed to meet 7.0% Reserve (W/DR & Interruptibles)	0	0	0	0
20	Surplus Resources Above 7.0% Reserve (W/DR & Interruptibles)	1,826	1,350	1,652	2,467
21	Existing Generation Without Capacity Contracts[8]	-682	-682	-682	-682

[1] 2006 estimate of the following Net Imports: **NW imports (COI) 4,000 MW minus exports to SP26 3,000 MW and TID/MID 450MW.**
[2] Demand forecast completed September 2005 as part of IEPR proceeding. CEC-400-2005-034-SF-ED2
[3] Planning Reserve calculation ((Total Generation+Demand Response+Interruptibles)/Normal Demand)-1.
[4] Based on CA ISO data.
[5] Does not include Demand Response/Interruptible Programs due to reserve margins in excess of 5% (Stage 2).
[6] Operating Reserve calculation ((Operating Generation-**Imports with Reserves**)/(Demand-**Imports with Reserves**))-1. See Footnote 1.
[7] Demand Response and Interruptibles added to Operating Generation in Reserve Margin formula from Footnote 6.
[8] Capacity is included in Line 1 and represents plants identified in 2004 CEC Staff Draft Report 100-04-005D Resource, Reliability and Environmental Concerns of Aging Power Plant Operations and Retirements
12/5/2005

Table 1-4: 2006 Detailed Monthly Electricity Outlook – CA ISO Southern Region (SP26)

(Megawatts)

	Resource Adequacy Planning Conventions	June	July	August	September
1	Existing Generation[1]	21,321	21,708	21,708	21,708
2	Retirements (Known)	-1,320	0	0	0
3	High Probability CA Additions	1,707	0	0	0
4	Net Interchange [2]	10,100	10,100	10,100	10,100
5	Total Net Generation (MW)	31,808	31,808	31,808	31,808
6	1-in-2 Summer Temperature Demand (Average)[3]	24,806	26,300	26,717	27,027
7	Demand Response (DR)	395	395	395	395
8	Interruptible/Curtailable Programs	950	950	950	950
9	Planning Reserve[4]	33.6%	26.1%	24.1%	22.7%
	Expected Operating Conditions				
10	Outages (Average forced + planned)	-1,070	-1,070	-1,070	-1,070
11	Zonal Transmission Limitation[5]	-150	-150	-150	-150
12	Expected Operating Generation with Outages/Limitations[6]	30,588	30,588	30,588	30,588
13	Expected Operating Reserve Margin (1-in-2)[7]	30.9%	21.2%	18.8%	17.0%
	Adverse Conditions				
14	High Zonal Transmission Limitation	-250	-250	-250	-250
15	High Forced Outages	-560	-560	-560	-560
16	Adverse Temperature Impact (1-in-10)	-1,937	-2,054	-2,086	-2,110
17	Adverse Scenario Reserve Margin[7]	14.7%	6.4%	4.3%	2.8%
18	Adverse Scenario Reserve Margin w/DR and Interruptibles[8]	21.2%	12.4%	10.2%	8.6%
19	Resources needed to meet 7.0% Reserve (W/DR & Interruptibles)	0	0	0	0
20	Surplus Resources Above 7.0% Reserve (W/DR & Interruptibles)	2,935	1,211	731	373
21	Existing Generation Without Capacity Contracts[9]	-3,040	-3,040	-3,040	-3,040

[1] Dependable capacity by station includes 1,080 MW of stations located South of Miguel.

[2] 2006 estimate of the following Net Imports: **DC imports 2,000 MW, SW imports 4,100 MW,** Imports from NP26 3,000 MW, LADWP Control Area imports 1,000 MW. **Imports with own reserves highlighted in bold.**

[3] September forecast showing adopted CEC 2005 IEPR high case forecast of 27,027 MW.

[4] Planning Reserve calculation ((Total Generation+Demand Response+Interruptibles)/Normal Demand)-1.

[5] Based on CA ISO data.

[6] Does not include Demand Response/Interruptible Programs due to Reserve Margins in excess of 5% (Stage 2).

[7] Operating Reserve calculation ((Operating Generation-**Imports with Reserves**)/(Demand-**Imports with Reserves**))-1. See Footnote 2.

[8] Demand Response and Interruptibles added to Operating Generation in Reserve Margin formula from Footnote 7.

[9] Capacity is included in Line 1 and represents plants identified in 2004 CEC Staff Draft Report 100-04-005D Resource, Reliability and Environmental Concerns of Aging Power Plant Operations and Retirements

12/5/2005

CHAPTER 1: THE DETERMINISTIC APPROACH

Resource Adequacy Planning

Line 1: Existing Generation

Existing generation accounts for thermal and hydro generation facilities operational as of August 1, 2005. Thermal generation consists of CA ISO control area merchant and municipal thermal resources (including non-hydro renewable), Investor-Owned Utility (IOU) retained generation, and Qualifying Facilities (QFs). The merchant thermal generation in SP26 includes 1,080 MW of contracted capacity from units located in Baja California Norte. Thermal unit capacity is derated to reflect summer operating conditions. The summer derate capacity can range from 90 to 96 percent of nameplate capacity based on the type of unit and location. Table 1-5 provides a more detailed breakout of existing generation.

Table 1-5: Derated Existing Generation

	SP26	NP26	TOTAL
CA ISO Control Area			
Merchant Thermal	13,679	13,306	26,985
Municipal Thermal	519	182	701
IOU Retained	3,540	2,343	5,883
Qualifying Facilities	2,536	2,803	5,339
Derated Hydro	1,047	5,939	6,986
TOTAL CA ISO	**21,321**	**24,573**	**45,894**
Non-CA ISO	6,662	3,606	10,268
STATEWIDE TOTAL	**27,983**	**28,179**	**56,162**

Hydroelectric capacity includes a minor derate for low-water-year conditions. The historic record shows that while dry conditions can have a significant impact on available energy, dependable capacity at peak does not significantly change during a low water year. The Non-CA ISO generation totals include thermal and hydro capacity.

Lines 2 and 3: Retirements and Additions

Table 1-6 provides a listing of the dependable capacity of all additions and retirements included in Lines 2 and 3.

Table 1-6: 2006 Additions and Retirements

CA ISO Control Area

SP26			NP26		
Additions			**Additions**		
Name	**MW**	**Expected**	**Name**	**MW**	**Expected**
Malburg	129	Jan-06	San Francisco Peaker	40	Jun-06
Riverside ERC	86	Feb-06		**40**	
Mountainview	1012	Feb-06			
Palomar Escondido	480	Jun-06			
	1707				
Retirements (Known)			**Retirements (Known)**		
Mohave	-1320		Hunters Point 1/4	-219	
	-1320			-219	

Non-CA ISO Control Areas

LADWP & IID Control Areas			SMUD & TID Control Area		
Additions			**Additions**		
Name	**MW**	**Expected**	**Name**	**MW**	**Expected**
			Ripon	86	Jan-06
			Walnut Energy Center	240	Apr-06
			Cosumnes	480	Apr-06
				806	

Line 4: Net Interchange

Net interchange data is provided by the CA ISO and is calculated by using the 2005 metered import data then subtracting out the metered exports. Tables 1-7 and 1-8 detail the individual components to Line 4. The SP26 net interchange import numbers include increases in the Southwest imports by 400 MW above 2005 observed levels to account for capacitor upgrades on the Palo Verde-to-Devers line. The NP26 net interchange includes 3,000 MW of export to SP26. The export reflects the greater need of capacity in SP26 than in NP26 but does not imply that it is contractually obligated to be delivered into SP26. Dynamic imports are resources located outside of the CA ISO control area but scheduled by the CA ISO for import. One example is SCE's ownership portion of Hoover Dam generation capacity on the border of Arizona and Nevada.

Table 1-7: NP26 Net Interchange

Path 26	(3,000)
Net NW Imports	4,000
TID and MID Exports	(450)
Total	**550**

Table 1-8: SP26 Net Interchange

Path 26	3,000
Net DC Line	2,000
Net SW Imports	3,100
Net Dynamics	1,000
Net LADWP Control Area Interchange	1,000
Total	**10,100**

Line 5: Total Net Generation

Line 5 is the sum of Lines 1-4 and represents total available capacity before outages and limitations.

Line 6: 1-in-2 Summer Temperature Demand (Average)

The demand forecast used in Line 6 is the *Statewide 1 in 2 Electric Peak Demand by Load Serving Entity (MW), High Case* in the *CALIFORNIA ENERGY DEMAND 2006-2016 STAFF ENERGY DEMAND FORECAST, Revised September 2005* (CED 2006). A range of three forecasts was completed as part of the 2005 Integrated Energy Policy Report (IEPR) and has been vetted in a series of workshops in the IEPR proceedings. Complete documentation of assumptions and methodologies are included in that report. Staff selected the high forecast to be conservative.

For the Southern California region, CA ISO and Energy Commission staff differ on what the actual weather-adjusted peak was for 2005 and, therefore, the CA ISO staff and Energy Commission's 2005 IEPR demand forecasts for 2006 differ by about 600 MW.

Detailed 2005 load data from utilities has not yet been compiled. As a result, Energy Commission staff's comprehensive analysis on what temperature and load levels actually occurred last summer is not available for this outlook.

Lines 7 and 8: Demand Response and Interruptible Programs

There are several mitigation measures available to the CA ISO and individual utilities to respond to adverse conditions when operating reserves fall below minimum acceptable levels. Tables 1-9 and 1-10 detail the subscribed and observed IOU demand response for programs that are established at the CPUC and/or have been contracted by an IOU. Several of these programs are new or evolving, and participation may increase before the summer peak temperatures occur.

The SCE-observed totals in Table 1-10 represent the response they reported for August 25, 2005, in CPUC filings. The CA ISO called a Transmission Emergency on this date due to the loss of the Pacific DC Intertie line from Oregon. Staff used this plus a portion of SDG&E's subscribed programs (SDG&E was not asked to call on interruptible programs) as an estimate of interruptible programs for SP26. PG&E did not experience an event last summer that required calling on interruptible customers. Staff calculated the percentage of SCE-subscribed interruptible customers that responded to the event on August 25th and applied this to PG&E's subscribed totals as the basis of NP26 Interruptible estimates on Line 8. A detailed explanation of the demand response programs identified in Tables 1-9 and 1-10 follows:

I-6— SCE Traditional non-firm rate: provides discounted energy and demand charges for load subject to curtailment during Stage 2 or 3 system emergencies. Per-kWh non-compliance penalties are applied to consumption above the contracted firm service level during events.

E-19/E-20—PG&E traditional non-firm rates: provide discounted energy and demand charges for load subject to curtailment during Stage 2 or 3 system emergencies. Per-kWh non-compliance penalties are applied to consumption above the contracted firm service level during events.

AL TOU CP—SDG&E critical peak rate: On-peak energy charges increase to $1.80/kWh during "critical peak" events, defined as Stage 2 or 3 system conditions.
BIP—Base Interruptible Program: Relatively new interruptible program that offers demand charge credits for load subject to interruption during system emergencies. Significant per kWh penalties apply for non-compliance.

ACCP—Air Conditioner Cycling Program (SCE only): Residential and small - to medium-sized commercial and industrial customers receive a bill incentive to allow SCE to remotely cycle their AC during system emergencies or high demand periods. The incentive varies based on the percent time the customer is willing to have his equipment cycled off.

Smart Thermo—Smart Thermostat (SCE and SDG&E): Customers with communicating, programmable thermostats receive a bill incentive to allow the utilities to set their thermostats higher during periods of high demand or system emergencies.

OBMC—Optional Binding Mandatory Curtailment: Offers blackout avoidance during rotation outages for up to a 15 percent reduction in circuit load during events.

SLRP—Scheduled Load Reduction Program: Offers an energy credit in return for scheduled peak period load reductions.

RBRP—Rolling Blackout Reduction Program (SDG&E only): Offers energy credits for load reductions—obtained through self-generation—during Stage 3 system conditions. Fifteen minute response is required.

AP-I—Agricultural and Pumping Interruptible (SCE only): Provides energy credits on consumption above the contracted firm service level in exchange for emergency reductions. Per kWh penalties apply for non-compliance.

Smart Thermo—Smart Thermostat Program:

CPP-VCD—can't find the "VCD" acronym anywhere. Critical Peak Pricing: CPP rates offer discounts (energy, demand or both, depending on the particular design) in non-critical hours but charge a premium for energy consumed on a limited number of days when system conditions are forecast to be critical, typically due to high expected demand or supply shortfalls.

DBP—Demand Bidding Program: Participants are paid an incentive for load reductions during curtailment events that are "bid" in to the utility a day in advance. There is no penalty for not bidding or not fulfilling the bid obligation.

CAL-DRP—California Demand Reserves Partnership: Program aggregators provide a contracted amount of load reduction during curtailment events by aggregating participant load reductions. Aggregators are paid a monthly capacity reservation charge for contracted load reduction amounts and an additional energy payment for consumption avoided during curtailment events.

C/I 20/20—20/20 for Commercial/Industrial customers (SDG&E only): Operated only during summer 2005, a 20 percent bill credit was given to customers who reduced on-peak consumption by an average of 20 percent or greater over all critical peak days.

BEC—Business Energy Coalition: A pilot program in the PG&E service territory operated in partnership with The Energy Coalition, participants are paid a per kW incentive to reduce load during curtailment events. The Energy Coalition works with participating customers to develop customized load reduction strategies.

"Emergency" CPP and DBP—these programs operate the same as the CPP and DBP programs except that notification to customers is made day-of instead of day ahead. Incentives reflect the higher value of the load reduction.

Table 1-9: IOU Subscribed Demand Response and Interruptible Programs

Program	Subscribed SCE	Subscribed SDG&E	Subscribed PG&E
I-6 or E-19/E-20	717.2		294
AL TOU CP and RBRP		79.9	
BIP	85.1		28.8
ACCP	346.9		
OBMC	10		13.5
AP-I	26.6		
Smart Thermo	8.1	1.4	
Interruptible Sub-Total	1193.9	81.3	336.3
CPP-VCD	0.8	18.6	34.3
DBP	167.3	16	176.2
CAL-DRP	178.7	4.2	248.3
CI 20/20 or BEC		50.7	10.2
Demand Response Sub-Total	347	90	469
Total	**1541**	**171**	**805**

Source: IOU filings under PUC R.00-10-002 and R.02-06-001

Table 1-10: IOU 2005 Observed Demand Response and Interruptible Programs

Program	Observed SCE	Observed SDG&E	Observed PG&E
I-6 or E-19/E-20	606.5		N/A
AL TOU CP		1.4	
BIP	60.7		N/A
ACCP	151.7		N/A
OBMC	38.8		N/A
AP-I	57		N/A
Smart Thermo	8.3	1.3	N/A
Interruptible Sub-Total	923	2.7	N/A
CPP-VCD		4.3	
DBP		0.5	19.3
CAL-DRP	30.8	1.03	211
CI 20/20 or BEC		11.72	14.61
Demand Response Sub-Total	31	18	245
Total	**954**	**20**	**245**

Source: IOU filings under PUC R.00-10-002 and R.02-06-001

Line 9: Planning Reserve Margin

Line 9 provides the conventional planning reserve margin calculated in the same manner as in CPUC resource adequacy proceedings. The formula used to calculate the margin is:

((Total Net Generation + Demand Response + Interruptible) / Demand)) – 1

Expected Operating Conditions

As system operators get closer to the operating day, they have a better sense of what unit and transmission outages are going to be. Thus, instead of having a general contingency reserve like a planning reserve, they measure an operating reserve based on estimates of what actual conditions are going to be. In this scenario, we have quantified potential outages and zonal limitations to simulate conditions next summer.

Line 10: Outages (Average Forced and Planned)

Energy Commission staff calculated potential 2006 outages using the actual 2002 thru 2005 daily outage totals for the summer peak period provided by the CA ISO. There is a significant variation in the amount of capacity that can be forced out on any given day. Staff has conducted probability studies on outages in the SP26 region, and results are presented in detail in Chapter 2. The forecast outage total also includes a small number of scheduled outages.

Line 11: Zonal Transmission Limitations

Line 11, Zonal Transmission Limitations, represents the estimate of the amount of existing capacity contained in Line 1 that is unable to serve load due to transmission constraints within the Northern California or Southern California region. Actual 2005 summer data was used as a baseline, and net gains from transmission upgrades were then used to reduce the limitation. For summer 2006, the CA ISO estimates NP26 should not experience any limitations. However, SP26 will likely be constrained by 150 MW on a consistent basis, mostly as a result of the 1,080 MW of contracted generation located in Mexico that cannot be fully delivered into the control area.

Line 12: Expected Operating Generation with Outages/Limitations

Line 12 is the sum of Lines 1 – 4 and represents the total capacity available to meet load. Demand Response and Interruptible programs are not included as a resource in this line due to reserve margins being in excess of 7 percent in all regions.

Line 13: Expected Operating Reserve Margin (1-in-2)

Line 13 provides the monthly expected reserve margin under average temperature conditions. The formula used to calculate the margin is:

((Supply – Imports w/reserves) / (Demand – Imports w/reserves)) - 1

The net interchange numbers expected to carry their own reserves are Southwest, DC Line, and LADWP in SP26 (6,100 MW), and total interchange in NP26 (3,550 MW).

Adverse Operating Conditions

Energy Commission and CA ISO staffs have identified potential adverse conditions that could strain the operation of the system. This scenario includes the adverse condition of three simultaneous adverse conditions: high congestion, higher-than-summer-average outages, and hot 1-in-10 temperatures. These adverse conditions, alone or in conjunction, would impact system operation. While there is a reasonable probability that any one adverse scenario could happen at any time, it is less likely that two or more adverse conditions will occur simultaneously. Chapter 2's probabilistic study provides a more in-depth analysis of the likelihood of this occurring.

Line 14: High Zonal Transmission Limitation

Line 14, High Zonal Transmission Limitations, is based on actual 2005 data and represents the high congestion periodically observed during the summer months.

Line 15: High Forced Outages

To estimate Line 15, staff used the same 2002 thru 2005 daily outage totals for the summer peak period used in Line 10 and calculated the standard deviation of all data points. The adverse forced outage condition is one standard deviation above the average. A more detailed description is included in Chapter 2.

Line 16: Adverse Temperature Impact (Hot)

The demand forecast used in Line 16 is the Statewide 1 in 10 Electric Peak Demand by Load Serving Entity (MW), High Case from the CED 2006. Similar to Line 6, CA ISO and Energy Commission staff differ on what the actual weather adjusted peak was for 2005, and therefore, the CA ISO staff and Energy Commission's 2005 IEPR demand forecasts for 2006 differ by about 600 MW.

Lines 17 and 18: Projected Adverse Scenario Reserve Margins

Line 17 represents the reserve margin under the adverse conditions of high zonal transmission limitations, high forced outage conditions, and hot summer temperatures. It is calculated in the same manner as Line 13, adding the adverse temperature impact to demand and subtracting outages and transmission limitations from resources. Line 18 is the same calculation but includes demand response and interruptible programs as resources to mitigate low operating reserve margins. When operating reserves fall below the WECC Minimum Operating Reserve Criteria (MORC), the CA ISO will declare one of the following emergencies:

Stage 1

Actual or anticipated operating reserves are less than the MORC (about 7 percent). The general public is notified, and consumers are requested to voluntarily reduce their consumption of electric energy;

Stage 2

Actual or anticipated operating reserves are less than or equal to 5 percent. The general public is notified, and interruption of service to some or all selected customers may be required to avoid more severe conditions. Usually "Interruptible Customers" (those who have agreed to be curtailed during Stage 2 events in exchange for lower rates) are called upon to cut load in order to avoid involuntary load cuts;

Stage 3

Actual or anticipated operating reserves are less than or equal to 1.5 percent. This is the most severe emergency stage and indicates that, without significant CA ISO intervention, the electric system is in danger of imminent collapse. Involuntary curtailments to consumers (rotating outages) are required to maintain Operating Reserves above 1.5 percent. Rotating outage areas are decided upon by local utilities and take place in an equitable sequence.

Historically, the CA ISO could declare an emergency only if reserves fell below MORC for their entire control area. However, in 2005 new protocols and tariffs designed to be more responsive to the two primary sub-regions were implemented within their control.

Lines 19 and 20: Resources Needed or Surplus for 7 Percent Reserve Margin

Line 19 calculates the additional megawatts required to meet a 7 percent reserve during adverse conditions. Line 20 represents the surplus megawatts above a 7 percent reserve under the adverse scenario. Demand response and interruptible resources are included in both calculations. Based on the above assumptions, NP26 is expected to have a surplus of 3,411 MW, while SP26 may range from slightly above to slightly below the 7 percent reserve margin.

Line 21: Existing Generation That May Not Have Capacity Contracts

Line 21 represents the capacity from the aging power plants identified in the 2004 Energy Commission Staff Draft Report titled *Resource, Reliability and Environmental Concerns of Aging Power Plant Operations and Retirements* (Pub. no. CEC 100-04-005D). It is a placeholder estimate for existing generation that may not have capacity contracts with an LSE and does not have a 2006 RMR contract with the CA ISO. Generating units without RMR or other contracts have limited ability to recover their operations and maintenance costs because they are not competitive through much of the year in the markets open to them. The resource adequacy and procurement proceedings that are ongoing at the CPUC may provide or have provided an opportunity for many of these units identified in Table 1-11 to secure capacity contracts for 2006 and beyond. Staff does not have information on the contract status of these particular units, and we note that there are modern units that also do not have RMR or capacity contracts.

Table 1-11: Existing Generation without Capacity Contracts as of 2004

SP26			NP26		
Name	**MW**	**At Risk Year**	**Name**	**MW**	**At Risk Year**
Coolwater 1/2	-146	2006	Pittsburg 7	-680	2006
Mandalay 1/2	-433	2006		**-680**	
Ormond Beach 1/2	-1491	2006			
Encina 4	-300	2006			
El Segundo 3/4	-670	2006			
	-3040				

CHAPTER 2: THE PROBABILISTIC APPROACH

Staff is in the initial stages of developing a full probabilistic assessment to enhance the deterministic tables we have historically provided. This first stage studies the probabilities of high demand and forced outages in the Southern California portion of the CA ISO Control Area. These two criteria were selected for initial study because data was readily available and weather and outages have significant impacts on the overall system operation. The SP26 region was selected because it has the highest probability of not meeting reserve requirements under adverse conditions this summer.

In the staff's deterministic tables presented in Chapter 1, supply adequacy is estimated for two operating scenarios: expected and adverse conditions. This approach has two limitations. First, there is a possibility that demand can exceed the 1-in-10 condition, or actual observed forced outages may exceed one standard deviation above the average. Second, although there is a reasonable probability that any one of the three conditions in the adverse scenario could happen at any time, it is progressively less likely that they will occur simultaneously. Adding all three simultaneously may be overly conservative and understate the expected reserve margin. This probabilistic assessment evaluates the complete range of demand and forced outage occurrences based on historical data and assesses what the possibility is of two or more adverse conditions occurring simultaneously.

Probability of Demand

To account for the effect of temperature on demand, staff developed a temperature response adjustment for varying degrees of hotter-than-average temperatures. To develop multipliers, staff estimated the relationship between temperature and daily peaks using recorded 2004 hourly loads reported to FERC by SCE and SDG&E, and a three-day moving average of daily maximum temperatures weighted by the number of air conditioning units estimated to be in each region. The estimation included weekdays from June 15th through September 15th, on which the weighted average maximum temperature was above 75 degrees in SCE, or 70 degrees in SDG&E service territories. Figures 2-1 and 2-2 show the 2004 relationship between temperature and load and the estimated weather response function for SCE and SDG&E, respectively. The coefficients shown, 317.33 and 66.53, indicate the MW increase in peak demand for each degree the temperature rises.

Figure 2-1: SCE Load vs. Temperature Relations

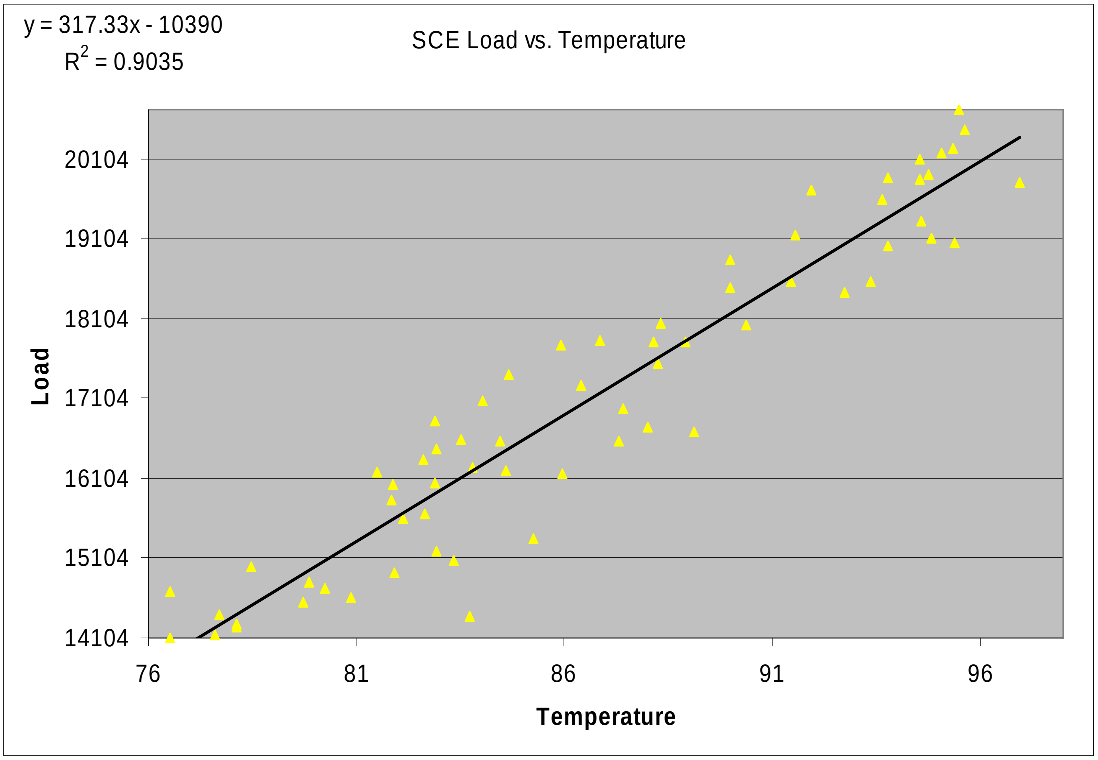
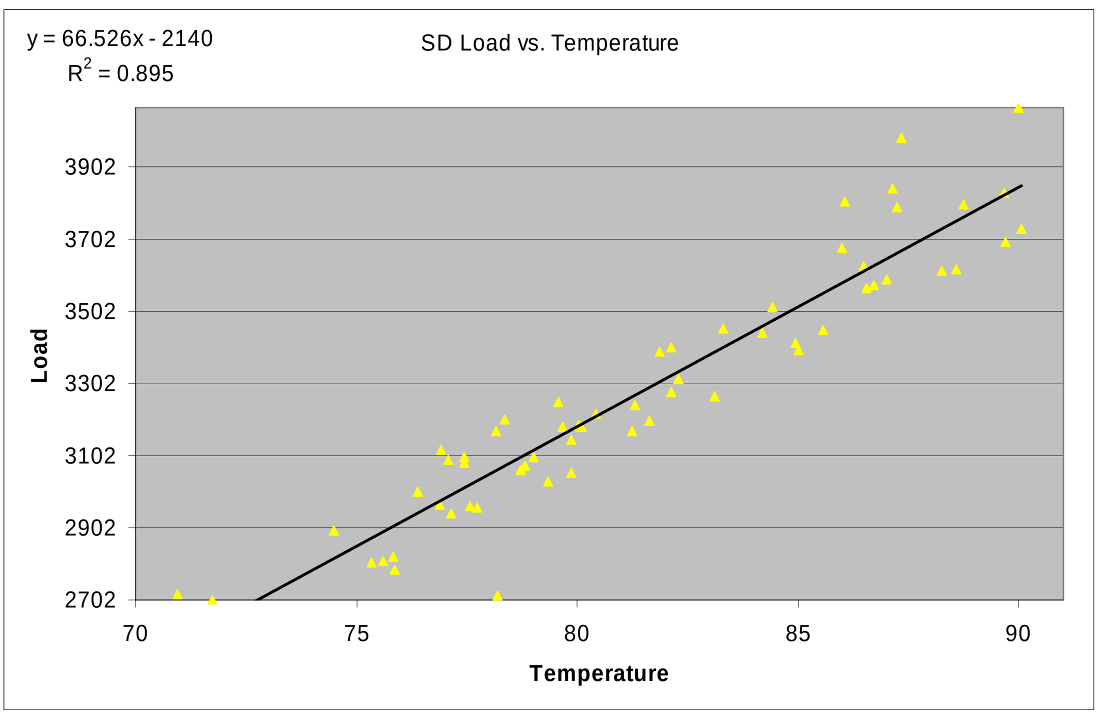
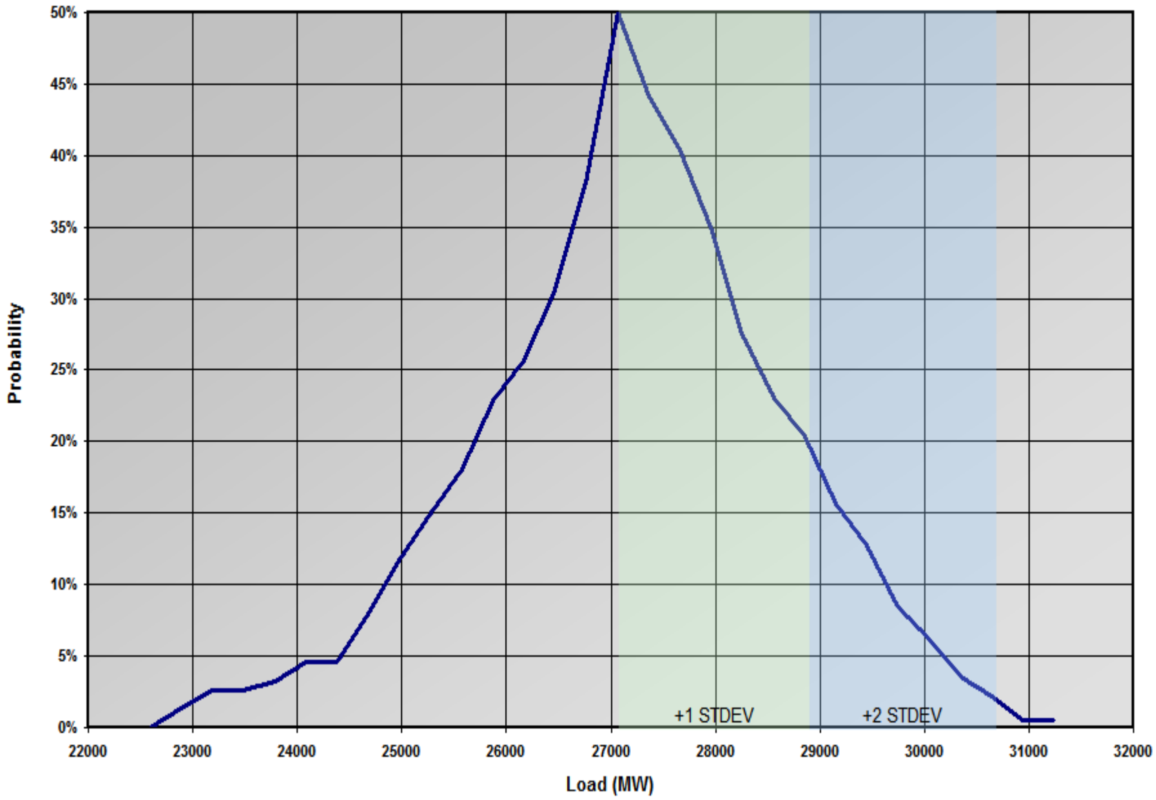


Figure 2-2: SDG&E Load vs. Temperature Relations



The estimated parameters were then applied to 54 years of historic weather data to calculate a distribution of Summer 2006 peak demand possibilities. The resulting probabilistic graph for Southern California is presented in Figure 2-3. It characterizes the probability of aggregated load occurring for the whole Southern California region.

Figure 2-3: Probability of Demand CA ISO SP26 Summer 2006



As Figure 2-3 shows that the range of SP26 demand in 2006 could be as low as 22,589 MWs or as high as 31,239, with a ‘most likely’ demand of 27,027 MW. While the forecast could equally likely be higher or lower than the mean, for planning purposes we are more concerned with the risks associated with the higher options. Staff estimates a 20 percent probability that the demand will be as high as 28,875 MWs, and a 3 percent probability that it will be as high as two standard deviations or 30,675 MWs.

Probability of Forced Outages

Similar to the impact and range of possible demand, the magnitude of the total available resources can be expected to fall within a range of uncertainty due to the variation in forced outages. Energy Commission staff calculated potential 2006 outages using actual 2002 thru 2005 daily outage totals for the summer peak period provided by the CA ISO. This set of data was statistically processed, and the results are presented in Figure 2-4.

Figure 2-4: Probability of Forced Outages
CA ISO SP26 Summer 2006

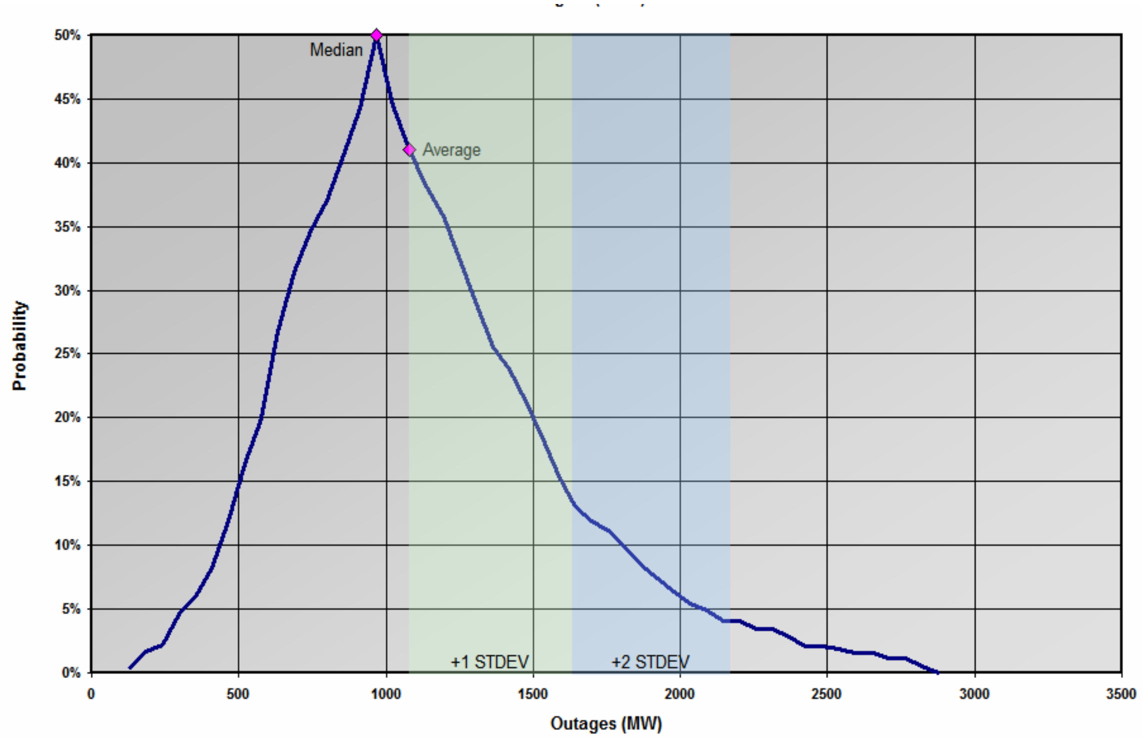


Figure 2-4 shows the range of SP26 forced outages in 2006 could be as low as 128 MWs or as high as 2,875 MWs, with a 'most likely' outage number of 969 MW. Again, for planning purposes, we are more concerned with the risks associated with the higher options. Staff estimates a 14 percent probability that forced outages will be as high as 1,629 MWs, and a 3 percent probability that they will be as high as 2,178 MWs.

Probability of Maintaining Minimum Required Operating Reserves

Methodology

The Supply Adequacy Model (SAM) developed by Energy Commission staff allows the user to look at the wider range of future conditions and presents the results in a probabilistic format. The SAM is a multi-regional, probabilistic forecasting model that assesses resource adequacy during the coincident peak load hour for a specified region or a group of regions. It is based on the Microsoft platform and uses Excel spreadsheets in combination with Visual Basic macros language.

This pilot study focused on Southern California, starting with the baseline assumptions presented in Table 1-4 in Chapter 1. These assumptions, with the exception of demand and forced outages as described above, are assumed to be fixed. Generation resources are aggregated; transmission and distribution outages are not considered; and imports and exports with other regions are characterized by an aggregate capacity of net interchange. These simplifications required a modified version of the model, called SAM-A, to be developed and used in this study.

SAM-A preserved the basic principles of the original version but is simpler and takes less time to provide an answer. Similar to the original version, SAM-A assesses the supply and demand balances for the coincident peak load hour in a specified region and has the capability to address uncertainty with respect to individual input variables.

The SAM-A exercises calculations in four major steps:

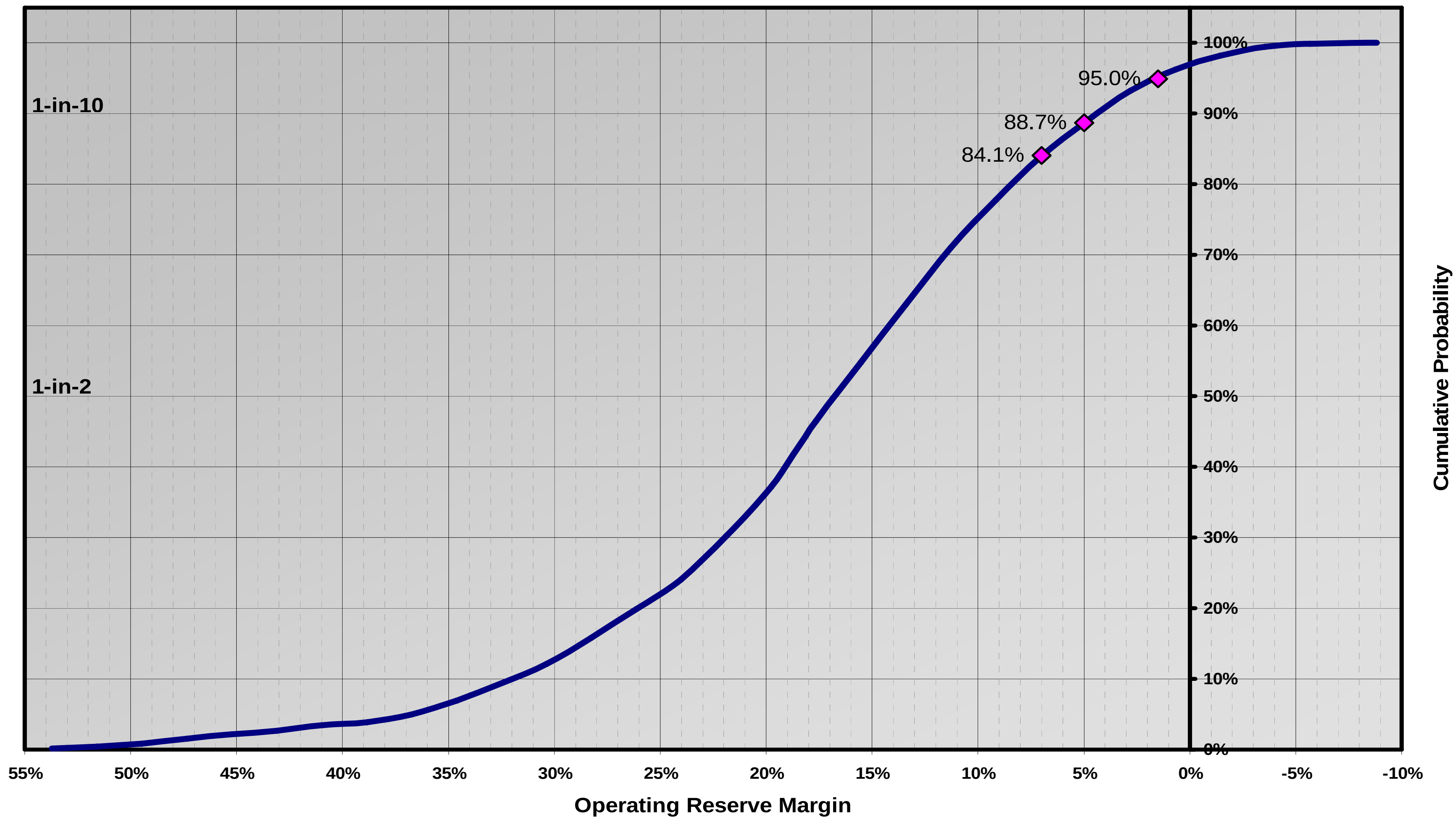
1. Using Monte Carlo draws, the model generates a deterministic case of input data in which each uncertainty factor (demand and forced outage) takes a random value from its respective range of possible values;
2. Evaluation of the adequacy of supply is made for each deterministic case, using spreadsheet tables;
3. The above steps are repeated for multiple cases to reasonably cover all possible combinations of the values of the uncertain factors;
4. The resulting set of cases is statistically processed to calculate:
    a. The probability that there is <u>insufficient</u> capacity to meet the peak demand and maintain a given reserve margin.
    b. The probability that there is <u>sufficient</u> capacity to meet the peak demand and maintain a given reserve margin.

<u>Results</u>

Figure 2-5 shows the probability of meeting the minimum operating reserve margin based on historical load/temperature data and forced outage data. The critical points are those corresponding to the CA ISO stages of alert described in Chapter 1. As shown in Figure 2-5, the probabilistic forecast gives an 84.1 percent confidence that operating reserves will not be less than 7 percent, which corresponds to the CA ISO first stage of alert. The confidence level that the Southern California reserve margin will be higher than 5 percent (Stage 2) is 88.7 percent. Southern California has a 95.5 percent likelihood of meeting the 1.5 percent (the third stage of alert).

We also examined a case in which demand side options were employed for tight supply-demand situations. If operating conditions deteriorate and the operating reserve margin drops lower than 7 percent, the CA ISO can rely on demand response and interruptible programs. The resulting operating reserve in the region with demand response and interruptible programs included is shown in Figure 2-6. Demand response programs are assumed to start if the reserve margin falls below 7 percent. Interruptible program resources are included if reserve margins fall below 5 percent.

Figure 2-5: Operating Reserves (Not Including Demand Response or Interruptible Programs) CA ISO SP26 Summer 2006



With the demand response programs, the confidence that a Stage 1 alert will not occur is approximately 88.5 percent, an increase of more than 4 percent over the case without the demand response program. Similarly, implementation of the interruptible programs further increases the confidence that the respective stages of alert will not occur.

The results can be also interpreted in terms of risk, and the level of risk is a value that complements the confidence. For example, based on adverse temperature and forced outages occurring simultaneously, risk that reserve margins fall below 1.5 percent and requires the CA ISO to call involuntary load shedding is about 1 percent.

Next Steps For Probabilistic Analysis

This methodology is primarily focused on the individual probability of occurrence of a number of adverse conditions and the cumulative probability of these conditions occurring simultaneously to the extent that they impact minimum reserve margins. This first modeling effort only evaluated two adverse conditions, temperature and forced outages. Additional adverse conditions that may be assessed in future analysis if relevant data can be obtained include:

- High regional transmission limitations (congestion)
- High levels of humidity
- Intra-zonal transmission outages
- Inter-zonal transmission outages
- Power plant construction delays
- Power plant retirement
- Low Demand Response program participation
- Low Interruptible/Curtailable program participation
- Low hydro-electric capacity availability
- Day ahead weather forecast variations

SP26 was selected for this first effort because the lowest reserve margins are found in this region. The results of this analysis indicate that a similar analysis for NP26, CA ISO, or statewide regions will not identify critical areas for concern in these other regions. However, future analysis may also be completed for NP26, the CA ISO Control Area and the statewide system as conditions change in the future

Figure 2-6: Operating Reserves Including Demand Response and Interruptible Programs
CA ISO SP26 Summer 2006